BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE INVESTIGATION)
OF THE CONTINUED REASONABLENESS OF)
CURRENT SIZE LIMITATIONS FOR PURPA) CASE NO. GNR-E-02-1
QF PUBLISHED RATE ELIGIBILITY)
(i.e., 1 MW) AND RESTRICTIONS ON)
CONTRACT LENGTH (i.e., 5 YEARS))
___________________________________)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JAY K. JOHNSON

Q. Please state your name and business address for the record.

A. My name is Jay K. Johnson. My business address is 303 Second Street, Suite 700 North, San Francisco, California.

Q. By whom are you employed and in what capacity?

A. I am Vice President and Area Manager for PB Power, Inc. PB Power is a Parsons Brinckerhoff Company. Parsons Brinkerhoff is a global engineering company with over 250 offices and 9,200 employees. PB Power has engineered more than 75,000 MW of power at over 300 sites around the world.

Q. What is your educational and professional background?

A. I received a Bachelor of Science Degree in Mechanical Engineering from the University of California, Berkeley in 1971. I am a professional engineer registered in California, Connecticut and Arizona. A more detailed description of PB Power's experience and my professional experience is attached to my testimony as Exhibit 101.

Q. What is the purpose of your testimony in this proceeding?

A. Several months ago Idaho Power requested that PB Power prepare a report which would provide a current estimate of the cost of constructing and operating a state-of-the-art 250 MW combined cycle combustion turbine sited in the vicinity of Boise, Idaho. They indicated that they were concerned that some of the cost assumptions currently used to compute their published avoided cost rates were outdated and they wanted me to provide more recent information. Included with my prefiled testimony as Exhibit 102 is a copy of the report PB Power submitted to Idaho Power in June of this year. The purpose of my testimony is to sponsor Exhibit 102 and to explain why I believe that the cost data presented in Exhibit 102 fairly represents the fixed and variable (excluding fuel) costs that Idaho Power would incur if it were to construct and operate a 250 MW, base-loaded combined cycle combustion turbine commencing operation in 2002.

Q. Could you please describe the specific CCCT which forms the basis for the costs contained in Exhibit 102.

A. The plant configuration is assumed to be a combined cycle plant using a single General Electric Frame 7FB combustion turbine generator and a single reheat steam turbine generator. The Frame 7FB represents GE’s latest upgrade to the 7FA, which went into production in 1994. The plant is configured with a three pressure HRSG and includes reheat and combustion turbine inlet air evaporative cooling to optimize plant performance. Air emission control equipment includes an SCR and CO catalyst to minimize NOx and CO emissions. The plant is designed for a northern climate with the CTG and STG indoors. An assumption was made that natural gas compression would be required. Two 100% capacity gas compressors are included.

Because of regional concerns for water usage, two cooling options were considered. The first was a conventional multiple cell mechanical draft cooling tower. This option provides the best overall plant performance at the lowest price. The second option considered was an air cooled condenser. This option minimizes water usage, but at a higher capital cost and at a reduction in overall plant performance.

The estimated capital cost of the facility described above is as follows:

Cooling Tower Option: $173,500,000

Air Cooled Option: $181,400,000

Dividing each option by the annual average net power output results in the following cost per kilowatt in 2002 dollars:

Cooling Tower Option: $686/kW

Air Cooled Option: $729/kW

Q. Please describe how the estimated capital cost of the facility described in your previous answer was computed.

A. The capital cost estimate was prepared using Thermoflow's PEACE software and adjusting the equipment pricing based upon pricing information obtained from recent projects. The PEACE software uses the heat balance model created in GTPRO as the basis of equipment sizing and then applies cost factors for equipment pricing, labor, bulk materials, equipment rental, construction supervision, engineering, procurement, startup and plant commissioning. In addition, "soft costs" were included for interest during construction, legal and financing expenses, permitting, insurance, bonds, spare parts, administrative expenses and contingencies. An allowance was also included for the natural gas pipeline interconnect and the electrical transmission interconnect.

Excluded costs included land, land leases and taxes as these costs may or may not be applicable.

Q. How did you determine the performance of the selected CCCT?

A. I prepared heat balances for the cycle using the Thermoflow software, GTPRO. This software contains the latest performance data on a wide range of combustion turbines including GE’s Frame 7FB. The combustion turbine performance is matched with an HRSG and a condensing steam turbine to develop the power cycle. Site specific meteorological data was obtained for the Boise area and this data was used to predict the performance of this plant configuration at this location. The annual average temperature and humidity for the Boise area is 51F dry bulb and 56% relative humidity. The site elevation was assumed to be 2,842 ft above sea level.

Once the annual average heat rate was calculated for each option, a degradation factor of 1.75% was added to account for unrecoverable losses between overhauls. The resulting annual average heat rates with degradation applied are as follows:

Cooling Tower Option: 6,899 Btu/kwhr HHV

Air Cooled Option: 6,994 Btu/kwhr HHV

Q. How did you determine the annual O&M costs for the facility?

A. Annual O&M costs were estimated using historical data from operating plants and by including the cost of a long term maintenance contract (LTMC) for the CTG. Cost data for the LTMC was obtained from GE. Costs were included for the replacement of the SCR catalyst and the CO catalyst as well as for consumables such as ammonia, cooling tower chemicals and water treatment chemicals. The plant was staffed for base load operation and allowance was included for spare parts.

Q. Have you compared the estimated site-specific costs of the CCCT presented in Exhibit 102 with cost estimates from other, more generic sources?

A. Yes, Idaho Power advised me that they had utilized generic data from the U.S. Department of Energy's Annual Energy Outlook (AEO) in making resource cost comparisons in their 2002 Integrated Resource Plan and asked me to compare the costs presented in Exhibit 102 with cost estimates made in the Annual Energy Outlook 2002.

Q. What was the outcome of that comparison?

A. The AEO 2002 report, Table 38, Cost and Performance Characteristics of New Electric Generating Technologies, indicates a cost of $435/kW for a conventional gas/oil combined cycle plant in the 250 MW size range. The report references several sources including various sources from industry, government and the Department of Energy National Laboratories. The costs provided were exclusive of interest charges, but there was no specific listing as to the breakdown of the estimate. This cost per kW compares closely with the $436/kW listed in the Gas Turbine World (GTW) Handbook 1998-1999. Closer review of the GTW figure indicates that the budget cost of $436/kW is for a basic, no frills plant and does not include soft costs such as interest during construction, legal and financing expenses, permitting expenses, insurance, bonds, spare parts, administrative expenses and contingency allowance. In addition no allowances were included for utility interconnects, buildings, pollution control equipment, gas compression or a plant distributed control system.

In order to arrive at an all-in cost per kilowatt it is necessary to include all reasonable soft costs, typical interconnect costs, site specific costs and a contingency, which I did in our estimate.

The AEO 2002 Report includes a variable O&M cost of .52 mills/kWh and a fixed O&M cost of $15.61/kW. The estimated annual O&M cost, assuming 92% availability and 250 MW net output is $4,950,000 per year. Our estimate for the variable O&M is 3.3 mills/kWh and the fixed O&M is $9.50/kW. The estimated annual O&M cost is $9,020,000 per year.

It is difficult to determine the cause of the differences between the estimates, since the AEO Report does not define how the O&M costs are calculated. However, it should be noted that we have included a LTSC in our estimate, which accounts for half the annual O&M cost and we have included the replacement costs of the SCR and CO catalysts, which may not have been accounted for in the AEO Report.

Q. In your expert opinion are the cost estimates contained in Exhibit 102 reasonable for a CCCT sited in the Boise vicinity in 2002?

A. Yes.

Q. Does this conclude your direct testimony?

A. Yes, it does.